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Smart Operations: Cutting Costs By Use of Simple Completion Solutions in the South Pars Field, Offshore I.R. Iran

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Abstract
In this paper we will discuss optimization of completion solution in the South Pars field. By means of simplified completion methods, completion and testing time has been cut by more than 50% compared to the time spent on previous completions in the South Pars field.

We will discuss why we decided to change the “standard South Pars completion solution” commonly used by all other operators in the same field, and we will present the operational results from the first fourteen wells.

Introduction
The South Pars field is located offshore Iran in the Persian Gulf. The field is divided into several phases, or offshore blocks, which are being developed in different stages over time (Figure 1). The allocated development area for phases 6, 7 & 8 comprise of three adjacent 10 km by 10 km blocks, in the centre of the Iranian sector, but on a crestal portion of the field.

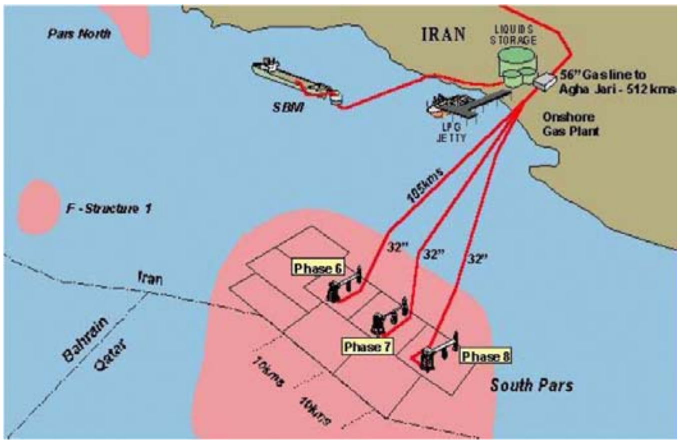

Figure 1

In year 2000, Iranian oil company Petropars Ltd. was awarded the rights to develop Phases 6, 7 & 8 (SP 6-8) of the South Pars field. Two years later, in 2002, Norwegian oil company Statoil signed a Participation Agreement with Petropars Ltd., whereby Statoil became the technical operator for the three phases. Statoil’s responsibility as operator covers the offshore part of the development, such as offshore pipelines, well head platforms, production topsides, and drilling and completion of the wells. The development is done in close cooperation with Pars Oil and Gas Company (POGC), which is responsible for the overall South Pars Field development on behalf of National Iranian Oil Company (NIOC).

As part of the Service Contract between Petropars and POGC, a Master Development Plan (MDP) was prepared. This MDP defines the scope of work for the development, and has also been the basis for all of the previous South Pars phases.

The development is based on unmanned well head platforms with connected bridges and flare platforms, which will be located centrally in each of the development blocks (Figure 2).

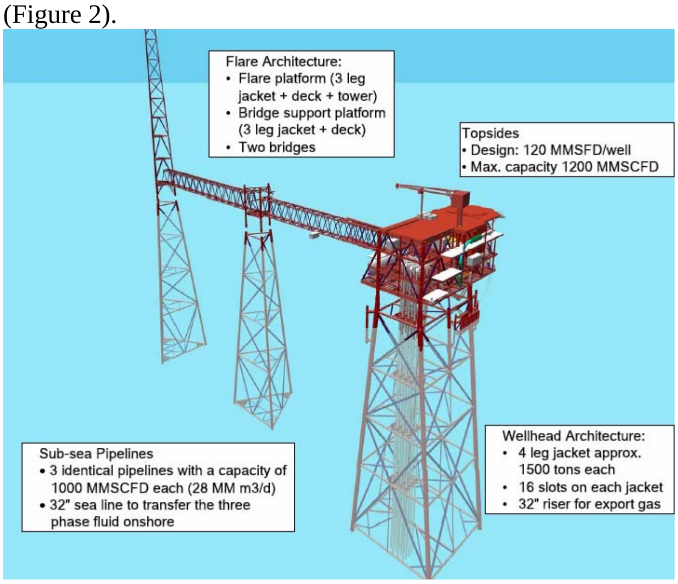

Figure 2

From each of the well head platforms 10-12 production wells will be drilled, to deliver a total target gas plateau rate of 1,000 million Scf/day per phase.

In Phase 1, which was completed in 2004, two well head (WH) platforms with 6 wells on each have been drilled and completed. Phases 2 & 3 were completed in mid year 2003, with one WH platform in each phase and a total of 21 wells completed. In Phases 4 & 5 drilling operations started in the beginning of 2003 from the two WH platforms and are still ongoing.

In SP 6-8 a total of 30 wells, 10 in each phase, are to be prepared for production. The appraisal well in each of the three phases is planned to be tied back and used as a production well. After installation of the WH platforms, the drilling operations started in the end of January 2004 in phase 6, early June 2004 in phase 7, and mid-December 2004 in phase 8.

Geology and Brief Reservoir Description

The field is located on the Qatar-South Fars Arch, which is a north-south elongated, regional flexure, considered to be the recent expression of movement on a major basement suture. The field is shared by Iran and Qatar (where it is known as the North Field). The feature forms a mega-regional anticline, which contains the world's largest known offshore gas field. Gas in the field is relatively sour and contains approximately 0.5% (5,000 ppm) hydrogen sulphide.

The late Permian Dalan Formation and the early Triassic Kangan Formation are the main gas producing reservoir units in the field. Kangan and Dalan Formations are divided into five major sequences called Upper Kangan and Khuff-1, -2, -3 & -4 (K-1, K-2, K-3 & K-4). The reservoir lithology consists mainly of dolomites, limestones, and minor anhydrites. Seven major depositional environments are identified, spreading from evaporitic sabkhas flats to offshore settings.

The productive sequence comprises four primary reservoir layers (K-1 to K-4). The lowest of the layers (K-4) contains the best reservoir quality as well as the richest gas. Gross reservoir thickness is between 400 m and 500 m.

The gas water contact (GWC) in South Pars varies over the field, it is deepest in southeast, and most shallow in northwest with a depth difference of around 400 meters from east to west over a distance of approximately 45 km. The contact-points are not always easy to pick and are often defined as "gas down to" (GDT). A surface, using the GDT and GWC depths in all available wells appears as a gently southeasterly dipping surface with an anomaly around SP-9, the appraisal well in phase 8. The GWC-surface modeled for phases 6 & 7 are based on the GDT observed in well SP-10 and SP-11 (appraisal wells in phases 7 & 8, respectively) and it seems like it is restricted to the dipping of the bedding. For phase 8 the GWC in defined slightly higher up than the GDT seen in SP-10 and SP-11.

In most wells on South Pars the contact is defined in the lowest part of K-4 were the reservoir properties are very poor and the contact coincide with and follows the dipping of the bedding surfaces. This observation indicates that the contact is restricted to the stratigraphy in some areas and not necessarily tilted because of an active aquifer.

General Well Design

The general South Pars well design, as outlined in the MDP, consists of the following (depths are as in phases 6-8):

- 26" conductor to 150-160 m TVD (Fars Group)
- 18 5/8" surface casing to 980-1030 m TVD (in Ilam formation)
- 13 3/8" intermediate casing to 1550-1650 m TVD (in Hith formation)
- 10 ¾" x 9 5/8" production casing to 2670-2810 m TVD (in Upper Kangan)
- 7" liner through the reservoir to 3050-3140 m TVD (in bottom of K-4)

All the well paths are designed with a two-dimensional J-profile with a planned horizontal displacement of minimum 2000 meter (Figure 3).

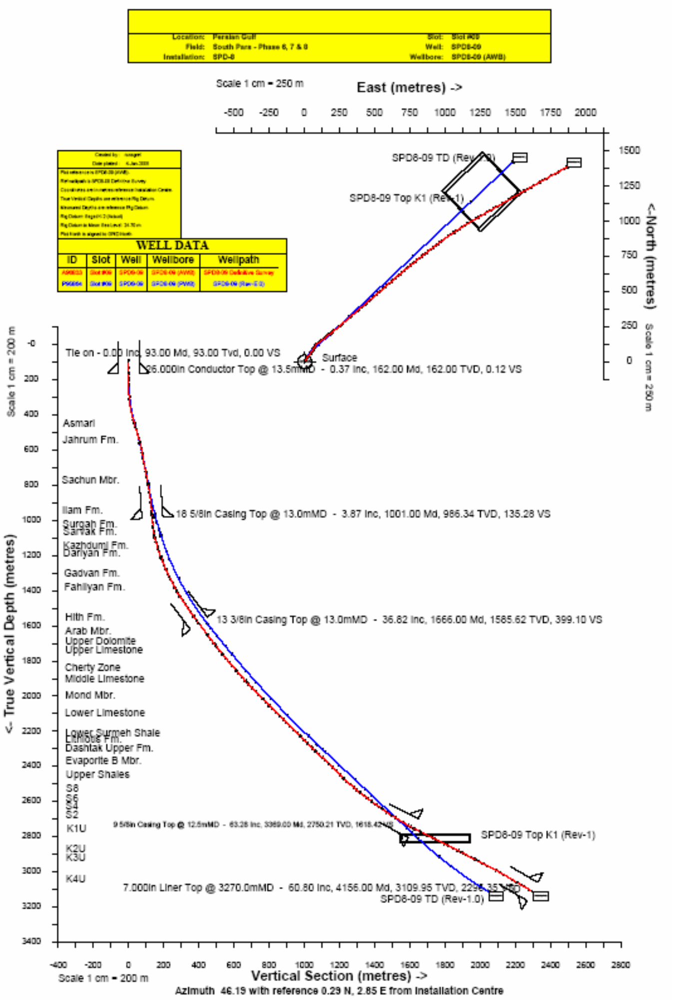

Figure 3

Setting Depth of 9 5/8" Casing. The recommendation from the MDP was to have the 9 5/8" casing shoe in the Upper Sudair (±2,400 m TVD). An important success criteria for the open hole completion solution (pre-drilled liner) was to be able to isolate the Sudair Formation, with the troublesome Lower Sudair and Aghar shale members. In order to achieve this, the 9 5/8" casing shoe needed to be set as close as possible to top reservoir. Based on the offset wells, we also believed that by covering the Sudair Formation with the 9 5/8" casing, many time consuming problems in the 8 ½" reservoir section could be avoided.

Drilling Fluids. Based on offset data a KCl/polymer drilling fluid system with a sulfonated asphalt additive was chosen for drilling of the 12 ¼" section down to Upper Kangan. In the 8 ½" reservoir section, SW/gel/polymer and salt saturated polymer mud systems had previously been used in the other South Pars phases. It was decided to carry out formation damage tests on a conditioned KCl/polymer field mud with sulfonated asphalt, and on a salt saturated (1.20 sg NaCl) polymer mud. The return permeability tests showed that both mud systems were acceptable to use in the reservoir section with respect to formation damage. Based on the test and the overall drilling fluid program it was decided to use the same KCl/polymer/sulfonated asphalt mud system in the reservoir section as used in the 12 ¼” section.

Due to the poor environmental friendliness of the sulfonated asphalt product, search for an alternative product was given attention. Based on experiences from the North Sea, the sulfonated asphalt was successfully substituted with glycol in the 16” section towards the end of 2004.

Based on the observations from the 16” and 12 ¼” sections and indications of bit balling during drilling of the 8 ½” section, glycol was successfully added to the mud system for this section as well.

Batch Drilling. Similar to the other phases in South Pars, batch drilling was incorporated into the Drilling Program for SP 6-8. Repeating the same operational sequence was evaluated as having the best effect on the learning curve as well as being favourable with respect to logistics and costs.

In each of the three phases, two wells were initially drilled in batch in order to gain experience and observe for any inter-phase variations. In Phase 6, the first two wells were drilled to TD, completed and tested in order to qualify the pre-drilled liner solution. In Phases 7 & 8, two wells were drilled in batch down to top of the reservoir, in order to ensure that the planned setting depth for the 9 5/8” casing was achievable.

The philosophy for the rest of the drilling program was to drill as many sections as possible in each batch to get maximum effect on the learning curve. Due to the nature of the open hole solution (pre-drilled liner) the completion operations followed immediately after drilling of the 8 ½” section.

MDP Case Completion Method

The completion method described in the MDP calls for a 7” monobore completion with a 7” 28% chrome cemented liner through the reservoir section. Commingled flow from reservoir layers K-2, K-3 and K-4 were assumed to have the best gas and condensate production. These layers were to be perforated and subsequently acidized. The uppermost reservoir layer, K-1, was not to be produced due to expected high H_2S content and poor production capability.

The 28% chrome corrosion resistant alloy (CRA) liner material was recommended due to the corrosive nature of the reservoir fluids in order to allow for additional corrosion allowance with a required production lifetime of 25 years. After cementing and liner cleanout, a cement bond log should be run prior to perforating.

The liner should be run without an integral packer, due to concerns regarding reliability and being gas tight. A tieback packer was recommended run on a separate run into the liner top. The tieback packer should feature an extension for a monobore anchor seal and a seal assembly in the bottom for pressure integrity with the liner setting sleeve. The upper completion should then tie into the tieback packer by means of an anchor latch and seal assembly. The tubing material and completion accessories, including down hole safety valve, should be in 28% chrome or equivalent CRA material.

The completion method described in the MDP was used by all the operators of the other South Pars phases (Figure 4).

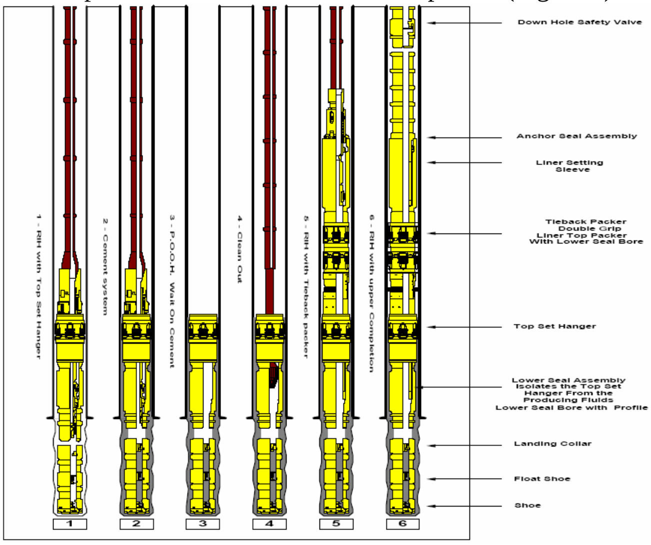

Figure 4

In addition to the operational activities shown in the above figure, a cement bond log is run in after the liner cleanout. After the tubing and upper completion is run, selected zones are perforated followed by acid stimulation.

Why Change Completion Method

The completion method described in the MDP is a very time consuming and expensive way of testing and completing wells. It had become the standard method for completing wells in the South Pars field and had so far been utilized in all phases from Phase 1 through Phase 5. Looking at data from earlier phases, the average completion and testing time spent on each well was 35 days. In the Participation Agreement, Statoil had committed to drill, test and complete each well within 72 days, with 12 days to be spent for completion and testing.

In order to achieve the operational target of an average of 12 days per well, it became evident that changes to the completion method had to be made. Bearing in mind the limited regional experience, ways of reaching the target without compromising well life or productivity was investigated. Best practice in Statoil with regards to completion of similar type gas wells was reviewed and the possibility of adapting these methods for use in South Pars was explored.

Due to the limited time available prior to start of operations, mainly standard components for 7” Monobore completions were selected. Design of new timesaving devices could not be performed should the project milestones be met on time. The solution had to be simple, and smarter than had been done in earlier developments in South Pars.

Open Hole (Pre-drilled Liner) Completion Method

After a thorough evaluation, permission was given by the client (POGC) to test out the chosen completion method on the first two wells to be completed. This was based on the potentially large cost and time savings that could be achieved by the new method, since electric logging in the reservoir section, cementing of 7” liner, perforation, and acidizing are not needed with the pre-drilled liner completion design.

The general outline of the operational sequence in the open hole completion method is (Figure 5);

1. Run 7” liner complete with scrapers and circulation sub in the running string.
   - Set liner hanger and liner packer.
   - Pull out with running tool, scrape and clean well & displace to seawater.
   - Perform inflow test and displace to completion fluid.
2. Run production packer, set and pressure test same.
3. Run tubing and upper completion complete with down hole safety valve and tubing hanger.
4. Install x-mas tree.
5. RU slick line and testing equipment, complete with flow lines and burner booms.
6. Pull prong and plug on slick line.
7. ‘Kick start’ and flow the well.

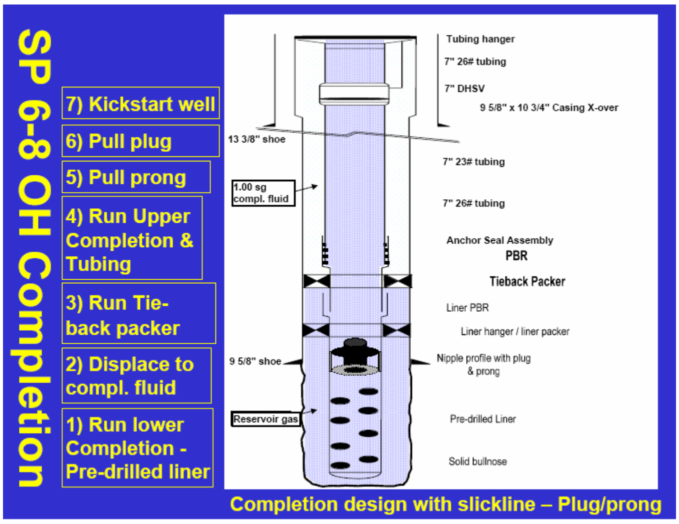

Figure 5

The Pre-drilled Liner. Rock mechanics studies indicated the wells could be completed and produced for 25 years without the need of any liner or cement in the reservoir sections. TD of the wells would be 50 mTVD above GWC, hence the risk of water production was considered to be very low in the lifetime of the field. For the first two wells it was decided to produce the entire reservoir sequence commingled, including K-1 which had not been produced in earlier phases. Reservoir studies had shown that K-1 reservoir layer produced in combination with the remainder of the reservoir would give a total content of H_2S in the produced hydrocarbons, well below the acceptance criteria dictated by the top side facilities.

This decision eliminated the need for isolation of the top reservoir section and made it possible to install the liner, clean out the 9 5/8” x 10 ¾” casing and displace the well to completion fluid all in one trip in the hole.

In earlier phases in South Pars the K-1 reservoir has been isolated by use of 7” 28% Cr liner and the lower part of the liner has been 13% Cr material. Initially the first intention was to complete the wells barefoot. This was based on the fact there was no need for any form of solids control or zonal isolation. However, it was decided to install a 7” 29 lbs/ft 13% Cr, L-80 liner across the entire reservoir.

The 7” liner is received from the mill and holes are drilled locally. The hole pattern is 0.3” diameter, 60 degree phasing and 3 holes per foot. This is equivalent to the shot pattern used when perforating in the other phases in the field. Solid joints of liner are run across the non-productive anhydrite layers in between the reservoir sections and from bottom of liner hanger to top K-1.

A 5.75” nipple is installed below the liner hanger with a wire line (WL) plug and prong preinstalled. This plug, in combination with the liner hanger packer, forms the down hole barrier once the well is displaced to completion fluid.

The liner is run in on DP with 9 5/8” scrapers installed in the string just above the liner hanger. This allows for scraping of the packer setting area for both the liner hanger packer and the production packer inside the 9 5/8” casing. The liner is run to bottom of the 8 ½” section while scraping the 9 5/8”, then the liner is pulled 10 meters off bottom and set.

After having set the liner hanger packer, the down hole barrier is pressure tested positive to maximum expected wellhead pressure (WHP). The time spent for displacing and cleaning out the wells is reduced to a minimum. A pill train is pumped between the water based mud and the seawater. The seawater is pumped into the well holding a constant bottom hole pressure. Once an acceptable cleanliness is achieved the pressure on the casing is bled off in steps and the down hole barrier is inflow tested. The BOP is then opened and the well displaced to completion fluid at maximum rate.

The first two wells had hydraulically operated formation isolation valves installed, acting as down hole barriers during displacement. The valves failed to operate hydraulically in both wells and had to be opened by use of wire WL manipulation. The use of hydraulic valves were discarded after these failures and replaced by the method described in this paper.

Running the production packer and upper completion. The 9 5/8”production packer with a seal receptacle and anchor latch is installed in a separate run on DP. Below the packer a seal stem is installed. Once on bottom, the seal stem below the production packer is stabbed into the PBR above the liner hanger. This allows for smooth running of WL. The production packer is set by weight only. Prior to POOH the packer is pressure tested.

In the completion planning phase it was evaluated to install the production packer together with the 7” tubing in order to save one trip in the hole, but the risk analysis regarded the cost of failure being too high.

The production tubing is the single most cost driving component of the South Pars wells. The standard wells have been completed using 7” 26 lbs/ft, 28% Cr tubing. An optimized tubing design has allowed for running of only one third of the tubing string being 26 lbs/ft while the remaining two thirds are of a less costly 23 lbs/ft.

The connections used are standard connections for the field. However, due to the high tubing cost, much emphasis has been put on handling and make up of tubulars. Until now approximately 5000 joints of tubing have been run, with only one joint being damaged.

The tubing is run in hole with the seal assembly and an anchor latch on bottom. A DHSV is placed at approximately 170 m. Once on bottom, the tubing is run into an indicating collet in the seal receptacle. Once tubing hanger and tubing has been pressure tested the BOP is removed and x-mas tree installed and tested.

Wire Line Operations

The pre-installed prong and plug below the liner hanger is pulled using slick line. The main challenge has been to keep the well clean to allow for easy access for pulling of the prong and the plug. Typically, settling of barite from mud and dope/debris from running of drill pipe and tubing will accumulate on top of the plug. A lot of effort and focus has been put on reducing this risk throughout the entire completion operation. So far, only one prong/plug has not been retrieved successfully by use of slick line. In one well, SPD8-02T2, 17 meters of settled barite had accumulated above the prong/plug preventing access with slick line. The barite was later removed by use of coiled tubing and the prong and plug were retrieved.

Testing/Clean-up of the wells

The first two wells were tested using a full well test package including separator and advanced H_2S measurements. The subsequent wells have been cleaned up using only a choke manifold and data acquisition (Figure 6).

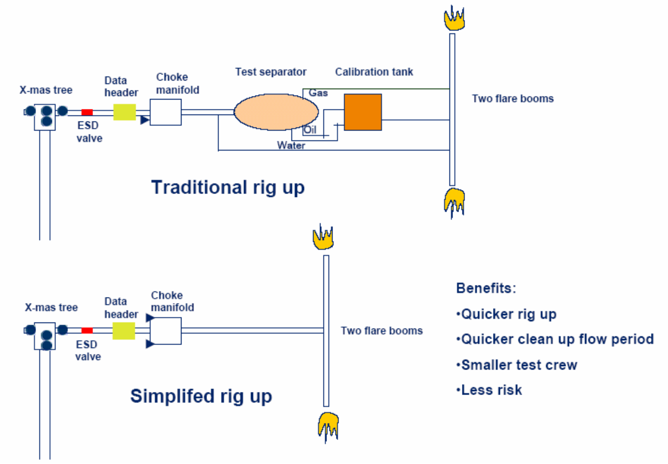

Figure 6

The main objective with the cleanup is to unload the drilling mud in the entire 8 ½" section and the completion fluid in the tubing. Further objectives are to measure H_2S, CO_2, and BS&W percentages in the produced hydrocarbons and measure productivity of the reservoir.

In order to reduce rig time spent on rigging up test equipment and lines, permanent test lines were installed from the test area to the burner booms on both rigs. The only operation requiring use of rig time is the hook-up and pressure testing of the coflex production hose to the x-mas tree. The remainder of the rig-up is done off rig time.

The wells are "kick-started" by bleeding off the WHP to zero as quick as possible. The well is then flowed to both burner booms through wide open choke for a short period of time, to allow for the entire mud column to be produced out of the reservoir section. Once gas is getting close to surface the well is choked back during the flowing of the mud/gas interface. The well is then beamed up on adjustable choke to desired maximum rate and stable FWHP has been reached. A sample set is then taken. Afterwards, the well is shut in for a short period of time until stabilized SIWHP.

Finally the wells are flowed through a fixed choke with an equivalent size to the adjustable choke used initially. All wells have been cleaned to a BS&W content of less than 5%. No more than 24 hrs have been spent on rigging up and clean-up of any well in the field.

The MDP calls for a minimum average flow per well of 100 million Scf/day and topside design of 120 million Scf/day per well. According to available test data, the majority of the wells in phases 6-8 have been tested to a higher production potential than the wells in other South Pars phases. One well has been tested to 150 million Scf/day, and all wells tested have produced with significantly higher rates than the requirement set forth in the MDP.

Conclusion

In the Participation Agreement, the estimated or budgeted time per well had been agreed to 72 days per well for a standard well (50^0 inclination), where estimated completion time was 12 days.

Offset data from the previous phases (SP 2 & 3) showed average completion times at approximately 35 days per well, and for SP 4 & 5 the average figures are so far just below 20 days. Total time, including drilling, averaged above 90 days per well for these phases (Figure 7).

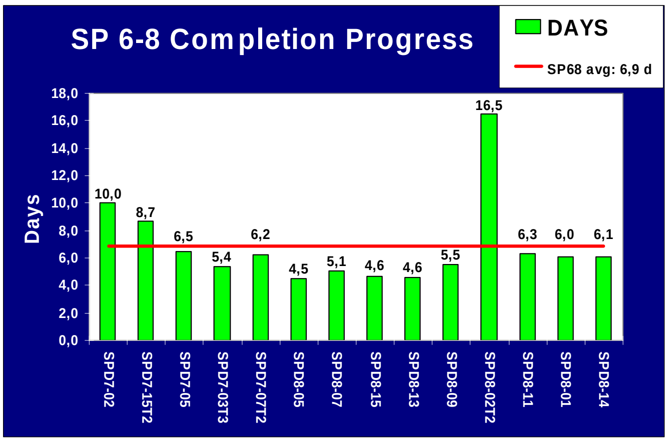

Figure 7

At the time of submission of this paper, 1 ½ year into the drilling campaign with 14 wells drilled and completed, the open hole completion design of the SP 6-8 wells have proven better both with respect to production potential as well as cost and time effectiveness.

The completion time, including testing, has been almost halved, and is now averaging 6.9 days compared to the targeted time of 12 days. Overall time per well, including completion and testing, is now averaging 44 days, with the best well at 30.3 days, compared to the targeted time of 72 days (Figure 8).

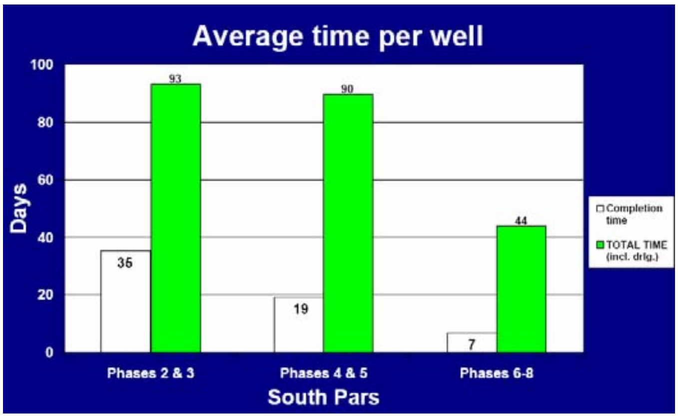

Figure 8

These results have been achieved through innovative engineering within the subsurface and drilling team, with particular focus on the detailed procedures throughout the operational phase. Another important success criterion has been focused team members both on- and offshore, with the abilities to continuously look for improvement areas and possibilities for optimization. Finally, it proves that simple completion solutions can be the most cost effective, and still give excellent production results.

As the development of Phases 6-8 in the South Pars field continues so does the optimization efforts.

Acknowledgements

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Reference

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